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Bi-Level Decomposition Approach for Coordinated Planning of an Energy Hub With Gas-Electricity Integrated Systems

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***Abstract*—Integration of multiple energy systems and the presence of smart energy hubs have provided increased flexibility and improved efficiency for the system. In this article, a bi-level decomposition approach (BLDA) is presented for coplanning of electricity and gas networks as well as the energy hub in distribution networks. The proposed multistage planning determines the investment candidates with optimum capacity for the components of integrated systems. Due to the complexity and nonlinearity of the models and energy subsystems interactions, the expansion planning problem is a difficult task with many limitations, especially for large-scale systems. To overcome these obstacles, achieve an optimum response and reduce computation time, a mixed integer linear programming model and a new BLDA methodology are developed in this article. Moreover, to evaluate the effectiveness and superiority of the proposed approach, the interactions among the energy systems are simulated in a large-scale distribution system and the results are compared.**

***Index Terms*—Active energy system, benders decomposition (BD), integrated expansion planning, multiple energy carriers.**

Nomenclature

$(i,j)/(n,m)$, h, t, u	Indices of electricity/gas nodes, hour, stage, hub, respectively
L^e, L^{th}, L^c	Electrical, heat, cooling load, respectively
$E^{\alpha s}$, $L^{\alpha s}$	Stored energy, loss of standby stored energy
P_G/Q_G, $P_{\mathrm{DG}}/Q_{\mathrm{DG}}$	Injected active/reactive power by the substation, DG, respectively
P_L, Q_L, P_D, Q_D	Active, reactive power flows in the line, power demand, respectively
S_G, S_{DG}	Apparent power of substation, DG, respectively
G_{GS}, G_{DG}, G_P, G_D	Gas injected at city gate, DG consumption, gas flow, demand, respectively
A_L^g, A_L^e	Nodes incidence matrix of gas, electricity, respectively
V_i, θ_i	Voltage magnitude, angle, respectively
P_n	Gas pressure at node *n*
G_{ij}, B_{ij}, Z_{ij}, R_{ij}, L_{ij}	Conductance, susceptance, impedance, resistance, length of line *ij*, respectively
nY, *nS*	Total number of years in each stage, number of stages, respectively
IC_F, IC_{DG}, IC_{GS}, IC_P, IC_S	Investment cost of feeder (*F*), DG, CGS, pipeline (*P*), substation (*S*), respectively
x_I, x_E, x_J	Binary variables for installation of new elements, expansion of existing elements, $x_J = x_I + x_E$, respectively
$\Delta(\bullet)_{\mathrm{y}}$	Discretization variable
$M^P{}_{dg}$, π	Auxiliary variables in linearization
η, γ	Dual variables in BD
tr, *bl*, *ac*, *d*	Transformer, boiler, absorption chiller, and discount factor, respectively
Ω_n, Ω_i	Sets of gas nodes connected to node *n*, electrical nodes connected to node *i*, respectively
Ω_G, Ω_E, Ω_{GM}	Sets of gas, electrical nodes, gas nodes with DG, respectively
Ω_{TP}, Ω_{TGS}, Ω_{TM}, Ω_{TF}, Ω_{TS}	Sets of types of the P, CGS, DG, F, S, respectively

Ω_P, Ω_F, Ω_{GS}, Ω_S	Sets of new installed and existing P, F, CGS, S, respectively
Ω_{IP}/Ω_{EP}, $\Omega_{IGS}/\Omega_{EGS}$, Ω_{IF}/Ω_{EF}, Ω_{IS}/Ω_{ES}	Sets of new installed/existing P, CGS, F, S, respectively
$(\bullet)^g$, $(\bullet)^e$	Gas, electricity network, respectively
$(\bullet)_f$, $(\bullet)_s$, $(\bullet)_p$, $(\bullet)_g$, $(\bullet)_m$	Type of F, S, P, CGS, DG, respectively
$\overline{(\bullet)}$, $\underline{(\bullet)}$	Maximum and minimum limits, respectively

I. Introduction

Integration of multicarrier systems (MCSs) provides an opportunity in both supply and demand sides for energy system planners and operators to move toward an efficient system [1], [2]. Ignoring the mutual effects of such systems, considering their integration and increasing interdependency, could create extraordinary risks in electricity networks [3]. Recently, the concept of the energy hub has been introduced as a key approach to multiple energy systems (MESs) [4], [5]. In the demand side, the electricity price increase has changed the planning of customers [6]. In addition, the widespread integration of distributed generations (DGs) has affected different services of energy systems including electricity, gas, cooling, and heat [7]. Also, the integration of these resources in distribution networks has provided some benefits for the local customers and entire system [8]. Right now, electrical and gas distribution networks and demand side resources are considered as decoupled systems and they are almost separately planned and optimized. However, integrated energy networks can lead to better technical and economic results in comparison with the decoupled ones [9]. To increase the interaction among energy carriers and flexibility in energy supply, and also reduce costs, new strategies, methods, and tools would be needed for economic planning and operation.

In recent years, the concepts of MCS and energy hub have paved the way for integrated planning. The planning and operation of microgrids and gas-fired DGs have been discussed as the common point of MCSs in [7]. In previous researches, the energy hub has been studied from different aspects including energy hubs modeling [10], optimal scheduling considering the uncertainty [5], and their development in urban areas [11]. Sheikhi *et al.* [10] have modeled smart energy hubs based on demand side management in electricity and gas networks. In [12], the economic optimal planning has been studied for interconnection of energy hubs considering the reliability criterion. These researches are mostly based on the independent operation and planning of energy hubs, and the electricity and gas networks expansion planning and power flow equations of both networks have not jointly been modeled.

The power flow studies of MCSs have been investigated in [13]. Also, a short-term scheduling in the integrated microgrids has been investigated considering the capability of the energy exchange with power market in [14]. Qiu *et al.* [15] have investigated the expansion planning of energy transmission networks considering social welfare and uncertainty. In [16], the generation, transmission, and gas networks integrated expansion planning has been examined. In that article, the meta-heuristic algorithms have been used for nonlinear problem solution. Qiu *et al.* have solved the planning problem of MCSs by presenting an MINLP model and using a fuzzy particle swarm optimization approach [17].

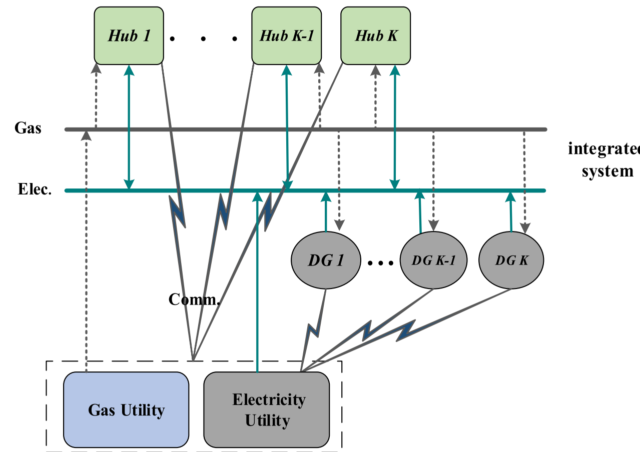

Fig. 1. Typical structure of integrated MCSs.

Most of these researches have focused on generation and transmission networks as a nonlinear model and this issue has less been addressed in the distribution level [7], [18], and [19]. In the most of studies on the distribution level, the common point for interactions between electricity and gas networks is only gas-DG resources. In other words, energy hubs and their internal elements on the demand side have not been considered, which can have a significant impact on the investment and expansion planning of both networks. The authors in [18] have dealt with a chance constrained programming model in the distribution network. In this article, the integrated planning of electricity and gas networks has been investigated with the aim of reducing operation and investment costs (ICs) of gas-DGs. However, the gas network expansion has not been considered.

In [19], a nonlinear framework has been studied for the optimal placing and sizing of gas-DGs, considering the reliability of multienergy distribution networks. In this article, the gas-fired resources that can have a significant impact on the gas network expansion have not been considered. This can cause gas network problems and as a result, some risks affecting the operation and security of power system [20]. Most importantly, the most of the models offered are an MINLP model that does not guarantee a global optimal solution. From practical viewpoints, the consideration of different types of load (i.e., electricity, heat, and cooling) and replacement and conversion of different resources would be needed to effectively assess the integrated energy system operation [21].

Fig. 1 illustrates a sample diagram of the integrated MCSs structure, generally presenting the interconnections between electricity and gas networks and energy hubs. The hub receives energy from electricity and natural gas carriers through the energy networks at the input and supplies electricity, heat, and cooling loads at its output. An energy hub with gas and electricity carriers represents a generalization of a bus in the integrated gas and electricity network.

In this approach, the owner of DGs is the operator of the electricity network, and the energy hubs interact with utility companies (electricity and gas). Further details of this approach (as a bi-level planning) and the structure of the energy hub will be described in Sections II and III, respectively.

In a real distribution system, if OPF is completely formulated, the result is normally a nonlinear model increasing the risk of divergence and its solution is a time-consuming and complex process [2], [13]. Some studies have used heuristic methods [22] to achieve the best possible solution. Compared with the classic methods, these methods have some disadvantages, e.g., high solution time, reduction of the model applicability, and possibility of trapping in local optima [23]. The authors of [24] have solved nonlinear gas flow with a fast forward substitution method. This article explains a short-term dispatch problem with low complexity and high computational burden. In [25], the convex relaxation techniques have been used for gas network constraints. However, it is nontrivial to guarantee evincible exactness of a convex relaxation and difficult to reconstitute an ac feasible solution when the duality gap is nonzero.

Liu *et al.* [26] have modeled an integrated energy system. In that article, the unit commitment problem has been modeled as an MINLP problem and the gas transmission has been based on successive linear programming (SLP). However, the SLP and MINLP models cannot guarantee the convergence. Adding expansion planning, integer variables, and nonconvexity to the problem could make the problem much more complex and thus leads to nonconvex feasible region with the possibility to have only a nonglobal optimal solution. The mixed integer linear programming (MILP) methods are robust, flexible, and able to solve problems with up to hundred thousands of binary and continuous variables.

Therefore, according to recent studies, a bi-level decomposition approach (BLDA) for coordinated planning of an energy hub with a gas–electricity integrated system is presented to bridge the gap. The most of previous studies have focused on generation and transmission networks. The major researches in the distribution level have considered only gas-DGs as interactions between two networks and have neglected the impact of the optimal operation of energy hubs on the distribution network planning, or have only considered the investment and development of a part of the integrated system. One of the reasons for not considering this issue is the complexity of the integrated demand-side planning compared to decoupled methods. Combining energy hubs for simultaneous planning of electricity and gas networks and providing a suitable approach to solve it are a challenging task. It is noteworthy that in large-scale systems, solving this problem is beyond the scope of existing analytical methods and, as a result, it becomes computationally intractable for commercial optimization software. Hence, there is a need for a practical and rapid computational methodology. In addition, an MILP model is needed for achieving a global optimal solution for such an integrated system.

Therefore, according to the existing literature, this article bridges the abovementioned gaps and the major contributions can be summarized as follows.

First, an MILP optimization technique has been developed to overcome the difficulties of the nonlinear optimization, achieve the optimal solution, and improve computational performance.

Second, suggestion of new BLDA methodology is made for coordinated planning of energy hubs with gas and electricity networks, decreasing the computational burden and problem complexity, and accelerating problem-solving process.

Finally, in the proposed optimization model, the effects of demand-side resources on simultaneous planning of electricity and gas networks are addressed using the concept of the energy hubs, considering different types of load (i.e., electricity, heat, and cooling) and replacing various energy carriers. Also, a successful validation of efficiency and evaluation of the proposed approach performance are performed on a complex large-scale MCS.

II. Problem Statement

In this article, a BLDA planning method is implemented. In the lower level, the energy hubs optimization problem is performed and in its upper level, the planning of the expansion of electricity and gas network is conducted. The decision making in the lower level is dedicated to the hub operator and the upper level is dedicated to the distribution network operator.

A brief description of these two layers and problem assumptions is given as follows:

1) *Planning model of electricity and gas networks*: In the upper level, the distribution network planner exchanges energy with energy hubs to decrease investment and operation costs. In this article, at first, the expansion planning of the distribution grid is carried out without considering energy hub as a decoupled and integrated electricity and gas network and in this case, the owner of DGs is the operator of the electricity network and the network owner is responsible for IC. In the next step, based on the output of the optimization problem of energy hubs, the expansion planning of gas and electricity grids is obtained.
2) *Planning model of energy hubs (lower level)*: The optimized performance of energy hubs is dependent upon its operation method. Thus, in this level, the optimal modeling of energy hubs is implemented by minimizing the total energy cost (EC) in the demand side. In this model, the external variables are relationship with the electricity and gas companies. Each energy hub is a township, where the hub owner is the decision maker/planner.

III. Model Description

In the presented model, the power flow and operation constraints of both networks (electricity and gas) are considered. The proposed planning is expanded with the purpose of minimizing investment and operation costs. In the proposed model, some candidates are considered for the expansion of network components and the optimal location, alternative and time for installation or the capacity increase of network components are determined.

In this section, at first, the nonlinear model of expansion planning of gas and electricity grids (upper level) and then, the energy hub model (lower level) are presented. It should be mentioned that in the proposed model, the operation cost is considered for the electricity distribution grid. The losses of gas networks are related to high-pressure compressor stations. The distribution networks do not usually have any compressors, thus, in this article, the operating cost of the gas network is not considered [27].

A. Upper Level Model

1) Electricity Network Flow Constraints: In the electricity network model, the expansion of feeders, substations, and DG resources are considered.

Constraints (1) and (2) impose the balance of active and reactive power at each node of the electricity network, respectively. Equations (3) and (4) define the active and reactive power flow of lines, respectively:

$$P_{G_{i,t,h}} + P_{\mathrm{DG}_{i,t,h}} - \sum_{j\in\Omega_i} A^e_{L_{ij}} P_{L_{ij,t,h}} = P_{D_{i,t,h}} \tag{1}$$

$$Q_{G_{i,t,h}} + Q_{\mathrm{DG}_{i,t,h}} - \sum_{j\in\Omega_i} A^e_{L_{ij}} Q_{L_{ij,t,h}} = Q_{D_{i,t,h}} \tag{2}$$

$$P_{L_{ij,t,h}} = \sum_{f\in\Omega_{T_F}} \begin{pmatrix} G_{ij}(V_{i,t,h})^2 - V_{i,t,h}V_{j,t,h} \\ \{G_{ij}\cos(\theta_{i,h}-\theta_{j,h}) \\ +B_{ij}\sin(\theta_{i,h}-\theta_{j,h})\} \end{pmatrix} .x_{JF_{ij,f,t}} \tag{3}$$

$$Q_{L_{ij,t,h}} = \sum_{f\in\Omega_{T_F}} \begin{pmatrix} -B_{ij}(V_{i,t,h})^2 + V_{i,t,h}V_{j,t,h} \\ \{B_{ij}\cos(\theta_{i,h}-\theta_{j,h}) \\ -G_{ij}\sin(\theta_{i,h}-\theta_{j,h})\} \end{pmatrix} .x_{JF_{ij,f,t}} \tag{4}$$

where P_G and Q_G stand for injected active and reactive power by the substation, P_L and Q_L are active and reactive power flows in the line, and P_D and Q_D are active and reactive power demand, respectively.

2) Flow Constraints of Gas Networks: The gas system typically includes gas producers, gas consumers, pipelines, and interconnection points [28]. In this article, pipelines, city gate substation (CGS), and interconnection points are considered for the modeling and expansion of the gas grid.

Similar to the electricity network, the gas network nodal balance equation and the gas flow in pipelines are expressed based on the Weymouth gas flow equations by (5) and (6) [29]:

$$G_{\mathrm{GS}_{n,t,h}} - G_{\mathrm{DG}_{n,t,h}} - \sum_{m\in\Omega_n} A^g_{L_{nm}} G_{P_{nm,t,h}} = G_{D_{i,t,h}} \tag{5}$$

$$G_{P_{nm,t,h}} = \left(\sum_{p\in\Omega_{T_P}} (x_{JP_{nm,p,t}}) \cdot C_{1_{nm,p}}\right) \cdot \sqrt{\left(P^2_{n,t,h} - P^2_{m,t,h}\right)} \tag{6}$$

where G_{GS} is the gas injected at city gate, G_{DG} is gas consumption of DG, G_D is the gas demand, and G_P is the gas flow in the pipeline.

3) Objective Function: The objective function in the upper level is described by (7), which represents the IC of new and existing (capacity increase) network components and operation cost:

$$Z = \sum_{t=1}^{nS} d^{(t-1)^{nY_t}} \left(IC_F + IC_{\mathrm{DG}} + OC_L + IC_{GS} + IC_P + IC_S\right). \tag{7}$$

The IC includes the cost of feeders (8), substations (9), DGs (10), CGSs (12), and pipelines (13). The operation cost of the electricity distribution grid that related to the energy losses is represented by (11):

$$IC_F = \sum_{ij\in\Omega_{IF}} \sum_{f\in\Omega_{T_F}} IC_{IF_{ij,f,t}} x_{IF_{ij,f,t}} + \sum_{ij\in\Omega_{EF}} \sum_{f\in\Omega_{T_F}} IC_{EF_{ij,f,t}} x_{EF_{ij,f,t}} \tag{8}$$

$$IC_S = \sum_{i\in\Omega_{IS}} \sum_{s\in\Omega_{T_S}} IC_{IS_{i,s,t}} x_{IS_{i,s,t}} + \sum_{j\in\Omega_{ES}} \sum_{s\in\Omega_{T_S}} IC_{ES_{j,s,t}} x_{ES_{j,s,t}} \tag{9}$$

$$IC_{DG} = \sum_{i\in\Omega_{E}} \sum_{m\in\Omega_{T_M}} IC_{IDG_{i,m,t}} x_{IDG_{i,m,t}} + \sum_{j\in\Omega_{GM}} \sum_{m\in\Omega_{T_M}} IC_{EDG_{j,m,t}} x_{EDG_{j,m,t}} \tag{10}$$

$$OC_L = d^{nY_t}\left[\sum_{ij\in\Omega_F} \sum_{h\in N_t} \sum_{f\in\Omega_{T_F}} \begin{matrix} nY_t.EP_h.L_{ij,f,t}. \\ R_{ij,f,t}\left[\left|\frac{(V_{i,t,h}-V_{j,t,h})}{Z_{ij,f,t}}\right|^2 .x_{JF_{ij,f,t}}\right] \end{matrix}\right] \tag{11}$$

$$IC_{GS} = \sum_{n\in\Omega_{IGS}} \sum_{g\in\Omega_{T_{GS}}} (IC_{IGS_{n,g,t}} x_{IGS_{n,g,t}}) + \sum_{m\in\Omega_{EGS}} \sum_{g\in\Omega_{T_{GS}}} (IC_{EGS_{m,g,t}} x_{EGS_{m,g,t}}) \tag{12}$$

$$IC_P = \sum_{nm\in\Omega_{IP}} \sum_{p\in\Omega_{T_P}} (IC_{IP_{nm,p,t}} x_{IP_{nm,p,t}}) + \sum_{nm\in\Omega_{EP}} \sum_{p\in\Omega_{T_P}} (IC_{EP_{nm,p,t}} x_{EP_{nm,p,t}}). \tag{13}$$

4) Limitations of Electricity and Gas Network: Constraint (14) imposes voltage limit at each node of the electricity network. The power flow limit in the lines is expressed by (15). Constraints (16) and (17) indicate limits of gas pressures in the nodes and gas pipeline capacity, respectively. Limits on maximum capacity of DG resources, substations, capacity of CGSs, and gas consumption of DGs are represented by (18)–(21), respectively.

Equation (22) guarantees that at a time, only one type of substation at each candidate node can be installed in the planning horizon. Moreover, for a set of components of the new candidates and a set of existing components, we have $x_E = 0$ and $x_I = 0$, respectively:

$$\underline{V_i} \leq V_{i,t,h} \leq \overline{V_i} \tag{14}$$

$$P_{L_{ij,t,h}}^2 + Q_{L_{ij,t,h}}^2 \leq \sum_{f\in\Omega_{T_F}} \overline{S}_{L_{ij}}^{\;2}.x_{JF_{ij,f,t}} \tag{15}$$

$$\underline{P}_n \leq P_{n,t,h} \leq \overline{P}_n \tag{16}$$

$$0 \leq G_{P_{nm,t,h}} \leq \overline{G}_P \tag{17}$$

$$P_{DG_{i,t,h}}^2 + Q_{DG_{i,t,h}}^2 \leq \sum_{m\in\Omega_{T_M}} \overline{S}_{DG_m}^{\;2}.x_{JDG_{i,m,t}} \tag{18}$$

$$P_{G_{i,t,h}}^2 + Q_{G_{i,t,h}}^2 \leq \sum_{s\in\Omega_{T_S}} \overline{S}_{G_s}^{\;2}.x_{JG_{i,s,t}} \tag{19}$$

$$0 \leq G_{GS_{n,t,h}} \leq \sum_{g\in\Omega_{T_{GS}}} \overline{G}_{GS_g}.x_{JGS_{n,g,t}} \tag{20}$$

$$0 \leq G_{DG_{n,t,h}} \leq \sum_{m\in\Omega_{T_{DG}}} \overline{G}_{DG}.x_{JDG_{i,m,t}} \tag{21}$$

$$\sum_{s\in\Omega_{T_S}} x_{IG_{i,s,t}} + x_{EG_{i,s,t}} \leq 1. \tag{22}$$

The gas-fired DGs, energy hub, and replacing various energy carriers are the factors of creating an integrated approach in MESs. In the proposed approach, the independent system operator manages the integrated expansion planning and energy market and gives the required solutions and guidelines for the interaction between the different operators and decision making for the investment to the owners of network assets such as Australian energy market operator.

5) Constraints for Electricity and Gas Coupling: The gas-fired DGs serve as the power source in electricity grid and gas load in gas grid. In the proposed model, the amount of the injected power by DGs into electricity network depends on the operation constraints and gas network expansion, while in the traditional planning the DG generation is only affected by the constraints of the grid operation. The model of gas-fired DG is representing by a quadratic function of output power with respect to the gas consumption [30]. The dependency of DG gas consumption upon its power output is expressed by (23):

$$G_{DG_{n,t,h}} = \sum_{m\in\Omega_{T_M}} \Big(\omega_{1_{n,m}}(P_{DG_{i,t,h}}) + \omega_{2_{n,m}}(P_{DG_{i,t,h}})^2\Big).x_{JDG_{i,m,t}} \tag{23}$$

where ω_1 and ω_2 are the fuel rate coefficients of DGs.

B. Lower Level Model

1) Energy Hub Concept and Modeling: Generally, an energy hub can be considered as an energy center, where different energy carriers can enter this center and after some conversions

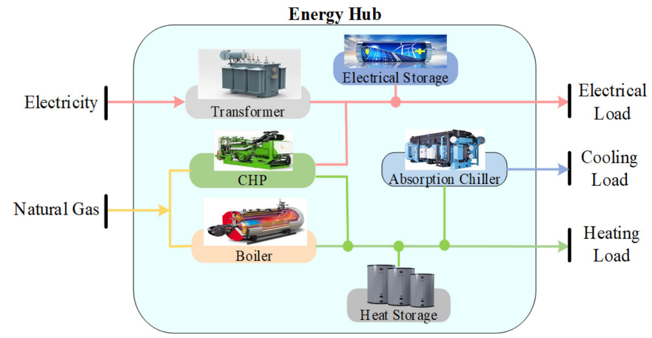

Fig. 2. General schematic of the energy hub.

and also using storage systems, it can supply the consumers at its outputs.

As shown in Fig. 2, the electricity and natural gas energy are the input carriers received through the energy networks and can supply electricity, heat, and cooling loads in its output. The CHP units are used to supply the electricity demand.

Also, electrical energy can be stored in the electrical storage system. The output of the boiler and CHP can be used to supply the heat load or be stored in the thermal storage system. The cooling load is supplied through the absorption chiller. Next, the energy hub model is expressed.

2) Energy Hub Modeling: The presented model in this article has focused on minimizing the total EC during the operation period of N_t. The total EC is expressed by (24):

$$\mathrm{EC} = \sum_{h,t,u} P_{h,t,u}^{e} EP_h + \sum_{h,t,u} P_{h,t,u}^{g} GP_h \tag{24}$$

where P^e and P^g, respectively, stand for input electric and gas power, and EP_h and GP_h are the electricity and gas prices, respectively. The demand-supply balance of the electrical power, heat, and cooling is expressed by (25) and (26), respectively. The capacity of the converters and dispatch factor are considered as (27)–(31):

$$L_{h,t,u}^{e} = (\eta_u^{tr} P_{h,t,u}^{e}) + (\nu_u^t \eta_u^{chp,e} P_{h,t,u}^{g}) - ES_{h,t,u}^{i} + ES_{h,t,u}^{o} \tag{25}$$

$$L_{h,t,u}^{th} = (\nu_u^t \eta_u^{chp,th} P_{h,t,u}^{g}) + ((1-\nu_u^t)\eta_u^{bl} P_{h,t,u}^{g}) - \frac{L_{h,t,u}^{c}}{COP_u^{ac}} - HS_{h,t,u}^{i} + HS_{h,t,u}^{o} \tag{26}$$

$$0 \leq \nu_u^t \leq 1 \tag{27}$$

$$\nu_u^t \eta_u^{chp,e} P_{h,t,u}^{g} \leq \overline{P}_{t,u}^{chp} \tag{28}$$

$$(1-\nu_u^t)\eta_u^{bl} P_{h,t,u}^{g} \leq \overline{P}_{t,u}^{bl} \tag{29}$$

$$P_{h,t,u}^{e} \leq \overline{P}_{t,u}^{tr} \tag{30}$$

$$L_{h,t,u}^{c} \leq \overline{P}_{t,u}^{ac} \tag{31}$$

where η is efficiency coefficient of each element, ν_u^t is dispatch factor, COP^{ac} as coefficient of absorption chiller performance, and ES^i, ES°, *his*, and HS° are input–output power of electrical and heat storage, respectively. The electrical and heat storages play as sources and loads while they store the required energy at the load peak and consume it during the load off-peaks. The change in the state of charging electrical (*e*) and thermal (*h*) energy storage is given by the following equations. Also, the constraints of the charging and discharging rates and stored energy in storage systems are considered as (32)–(37) [11]:

$$E^{es}_{h,t,u} = (1 - L^{es}_u)E^{es}_{h-1,t,u} + ES^i_{h,t,u}\eta^{ch,es}_u - \frac{ES^o_{h,t,u}}{\eta^{dch,es}_u} \tag{32}$$

$$E^{hs}_{h,t,u} = (1 - L^{hs}_u)E^{hs}_{h-1,t,u} + HS^i_{h,t,u}\eta^{ch,hs}_u - \frac{HS^o_{h,t,u}}{\eta^{dch,hs}_u} \tag{33}$$

$$\underline{E}^{\alpha s}_{h,t,u} \le E^{\alpha s}_{h,t,u} \le \bar{E}^{\alpha s}_{h,t,u}, \alpha \in e, h \tag{34}$$

$$\underline{\beta S}^i_{h,t,u} \le \beta S^i_{h,t,u} \le \overline{\beta S}^i_{h,t,u}, \beta \in E, H \tag{35}$$

$$(1 - \nu^t_u)\eta^{bl}_u P^g_{h,t,u} \le \overline{P}^{bl}_{t,u} \tag{36}$$

$$\underline{\beta S}^o_{h,t,u} \le \beta S^o_{h,t,u} \le \overline{\beta S}^o_{h,t,u}, \beta \in E, H. \tag{37}$$

C. Linearization of Equations

The planning model of gas and electricity network is a non-convex MINLP problem. Thus, an MILP model is proposed to deal with the nonlinear nature of the original MINLP problem by techniques such as, piecewise linearization and Taylor's series [23]. Since the MILP techniques are very mature, fast, and robust, and also they can treat problems with more than one million variables and thousands of constraints, therefore, it can be said that they are computationally tractable approaches [31].

Linearization of electric power flow Equations: The constraints (3) and (4) in the planning model are nonlinear. For a linear approximation of these constraints, some assumptions are considered that are commonly valid for the distribution network. First, using the piecewise linearization method, the bus voltage can be expressed as $\underline{\mathrm{V}} + \sum_{y=1}^{nY} \Delta V_y$, where, $\Delta V \ll 1$. Second, the voltage angle difference between two nodes of the line is small and approximately is less than 0.105 radians. Therefore, the simplifications $\sin(\theta_i - \theta_j) \approx (\theta_i - \theta_j)$ and $\cos(\theta_i - \theta_j) \approx 1$ can be used. It is noted that the terms $\Delta \mathrm{V}^2$, $\Delta \mathrm{V}\ (\theta_{i,j})$, and $(\theta_{i,j})^2$ are close to zero due to small values of $\theta_{i,j}$ and ΔV. Also, based on the first assumption, we have

$$V^2 = \underline{V}^2 + \sum_{y=1}^{nY} S^v_y \Delta V_y \tag{38}$$

$$V_i V_j = \underline{V}^2 + \underline{V}\sum_{y=1}^{nY} \Delta V_{i,y} + \underline{V}\sum_{y=1}^{nY} \Delta V_{j,y}. \tag{39}$$

Therefore, based on the above equations and the Big-M method, the linear approximation of (3) and (4) are givein in (40) and (41), shown at the bottom of this page.

Similarly, (4) is linearized.

Linearization of electricity network operation limits: The constraints (15), (18), and (19) are called circular inequalities. These constraints are a circular plate in *P-Q* coordinate. For linearization, the circular constraints are developed by a polygon. The sides of the polygon are straight lines characterized by tangents in the circle in different points [32], i.e.:

$$\sum_{y=1}^{Y} \left(\cos(y\Delta\alpha)P_{L_{ij,t,h}} + \sin(y\Delta\alpha)Q_{L_{ij,t,h}}\right) \le \sum_{f\in\Omega_{T_F}} \overline{S}_{L_{ij}}.x_{JF_{ij,f,t}} \tag{42}$$

$$\sum_{y=1}^{Y} \left(\cos(y\Delta\alpha)P_{DG_{i,t,h}} + \sin(y\Delta\alpha)Q_{DG_{i,t,h}}\right) \le \sum_{m\in\Omega_{T_M}} \overline{S}_{DG_m}.x_{JDG_{i,m,t}} \tag{43}$$

$$\sum_{y=1}^{Y} \left(\cos(y\Delta\alpha)P_{G_{i,t,h}} + \sin(y\Delta\alpha)Q_{G_{i,t,h}}\right) \le \sum_{s\in\Omega_{T_S}} \overline{S}_{G_s}.x_{JG_{i,s,t}}. \tag{44}$$

Linearization of gas flow equation and (23): The piecewise linearization and Big-M methods are used for the linearization of (6). Since this method has demonstrated an optimal implementation for gas network optimization, it is used for linearization

$$P_{L_{ij,t,h}} - \left(G_{ij}\left(\sum_{y\in\varphi_y}\left(S^v_y - \underline{V}\right)\Delta V_{i,t,h,y} - \underline{V}\Delta V_{j,t,h,y}\right) - (\underline{V})^2 B_{ij}(\theta_{i,h} - \theta_{j,h})\right) \le M\left(1 - \sum_{f\in\Omega_{T_F}}(x_{JF_{ij,f,t}})\right)$$

$$P_{L_{ij,t,h}} - \left(G_{ij}\left(\sum_{y\in\varphi_y}\left(S^v_y - \underline{V}\right)\Delta V_{i,t,h,y} - \underline{V}\Delta V_{j,t,h,y}\right) - (\underline{V})^2 B_{ij}(\theta_{i,h} - \theta_{j,h})\right) \ge -M\left(1 - \sum_{f\in\Omega_{T_F}}(x_{JF_{ij,f,t}})\right) \tag{40}$$

$$-\overline{P}_{L_{ij}}\left(\sum_{f\in\Omega_{T_F}}(x_{JF_{ij,f,t}})\right) \le P_{L_{ij,t,h}} \le \overline{P}_{L_{ij}}\left(\sum_{f\in\Omega_{T_F}}(x_{JF_{ij,f,t}})\right). \tag{41}$$

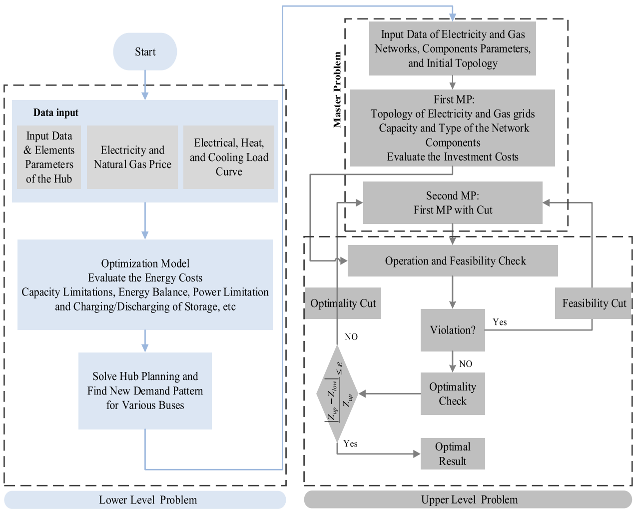

Fig. 3. Procedure of BLDA.

as follows [33]:

$$-M\left(1-\sum_{p\in\Omega_{T_P}} x_{JP_{nm,p,t}}\right)\leq G_{P_{nm,t,h}}$$

$$-\left(C_{1_{nm,p}}.\pi_{nm,t,h}\right)\leq M\left(1-\sum_{p\in\Omega_{T_P}} x_{JP_{nm,p,t}}\right) \quad (45)$$

$$\sum_{y=1}^{nY} S_y^{\pi}\Delta\pi_{nm,t,h,y}=\sum_{y=1}^{Y} S_y^{p}\left(\Delta P_{n,t,h,y}-\Delta P_{m,t,h,y}\right) \quad (46)$$

where y is the linearization segments index, S denotes the line slope, and M is a positive constant sufficiently large. The final linearized section is dedicated to coupling constraint of gas-fired DG resources in the electricity and gas networks as follows:

$$\begin{aligned}&-M\left(1-\sum_{m\in\Omega_{T_{DG}}} x_{JDG_{i,m,t}}\right)\leq G_{DG_{n,t,h}}\\&-\sum_{y=1}^{Y} M_y^{P_{dg}}.\Delta P_{n,t,h,y}^{dg}\\&\leq M\left(1-\sum_{m\in\Omega_{T_{DG}}}\left(x_{JDG_{i,m,t}}\right)\right)\end{aligned} \quad (47)$$

$$M_y^{P_{dg}}=P_{DG_{n,t,h}}\omega_{2_{n,m}}+\omega_{1_{n,m}}. \quad (48)$$

IV. Step-by-Step Methodology of BLDA Planning

Fig. 3 depicts the flowchart of BLDA planning model. As shown, in the upper level, the planning of the electricity and gas networks is performed and in the lower level, the optimization of energy hubs (demand side) is conducted.

In the lower level, at first, the inputs of energy hub problem and their parameters are processed for coupling and connectivity of the MESs. Then, the optimization problem, i.e., (24)–(37), is solved for calculating energy hub planning which provides the ECs and received power from the network.

The data of electricity and gas networks and the output of the optimization problem of the energy hub, e.g., the pattern of loads of the nodes with energy hub are received as the input of the expansion planning of the electricity and gas networks (see more details in Section II). Then, in the upper level, the planning problem of the energy networks expansion is solved based on a modified Benders algorithm. Indeed, to reduce the complexity of the integrated planning problem, a decomposition method based on Benders decomposition (BD) algorithm is used to solve the optimization problem. Therefore, based on the following problem, the original large-scale problem is divided into the master problem (MP) and subproblem (SP).

In the next step, the MP determines the topology of the electricity and gas networks, the capacity and type of the network components without considering the network operation constraints. In the MP1, the binary variables, i.e., existence of network components, and the objective function (ICs) are determined. Then, the output results are used for the evaluation of the SP. After that, the operation and feasibility constraints of the problem are checked through SP. The SP is based on linear programming duality [written in *max* form (49), shown at the bottom of the next page]. This process is continued as the repetition between MP2 and SP and the problem is modified based on the added cuts. This process continues until the upper and lower bound get closer adequately.

V. Implementation on Test System

A. Test System

The proposed expansion planning model is tested on a 9-hub test system, which has 54 nodes in the electricity grid and 50 nodes in the gas grid as illustrated in Fig. 4.

The energy hub includes the transformer, CHP unit, boiler, absorption chiller, and electrical and heat storages. In the proposed structure, according to the constant price of gas and assuming that the heat power cannot be sold to the network, no heat storage is used. The rest of the elements are installed in all hubs. The installed components of energy hubs are similar and their characteristics were studied in Section III.

The load factor curves (electricity, heat, and cooling) for a typical day and electricity and natural gas prices are depicted in Figs. 5 and 6, respectively [11], [34].

As shown, the gas price is fixed for the whole day, while the electricity price follows a time-of-use trend. This article is applied to a 10-year planning horizon in two stages with an average annual load growth rate and the discount rate of 6% and 7.1%, respectively [35].

The system power factor is assumed to be 0.9. The voltage limits at the load nodes are equal to [0.95, 1.05] p.u. Other required data about electricity and gas network and energy hubs are given in [11], [36].

All simulations of this article are implemented within the GAMS software package on a PC, 2.5-GHz Core i7 with 6 GB RAM. The following three cases are considered to evaluate the performance of the proposed energy hub-based integrated planning for the multicarrier energy infrastructures.

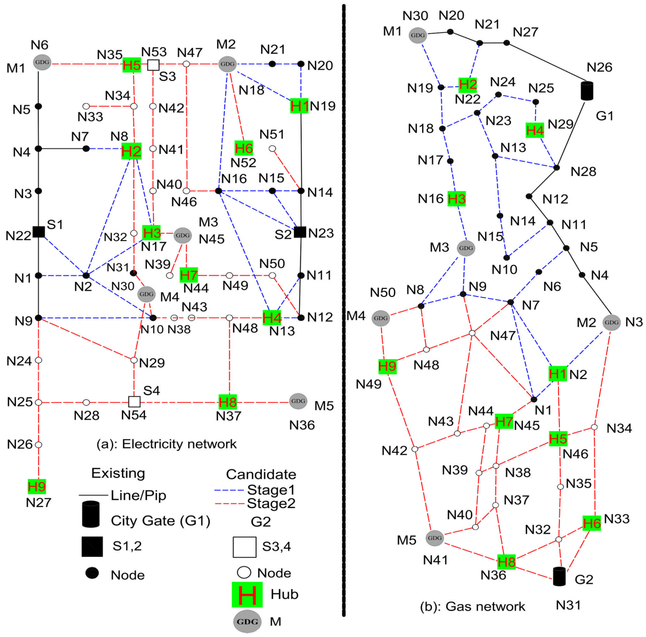

Fig. 4. Test system under study.

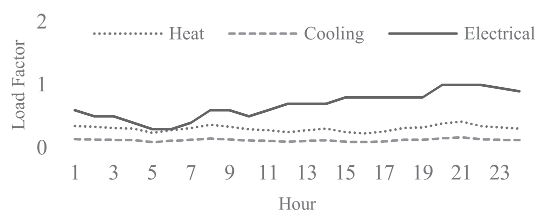

Fig. 5. Load factor curve (heat, cooling, and electrical).

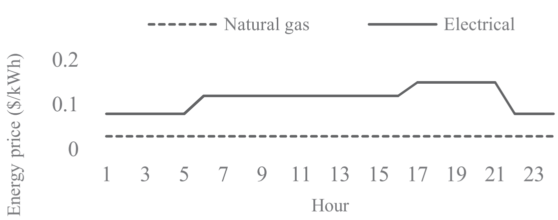

Fig. 6. Natural gas and electricity prices.

Case1: Planning of decoupled networks (DP).

Case 2: Coplanning of gas and electricity network with DG resources (CPD): In this case, DG generation is a decision-making variable for simultaneous optimal energy flow.

Case 3: Integrated expansion planning of energy networks considering the DGs and based on the hubs planning (IPDH).

B. Results and Analysis

Comparison and evaluation of the proposed model: In this section, a comparison is made between the variables and results of MINLP and MILP models. The deviation of the voltage range, voltage angle, and gas pressure in the MILP model are 0.41%, 0.62%, and 0.18%, respectively, in comparison to the MINLP model, and the deviation of the total active, reactive, and gas powers is 2.8%, 2.5%, and 0.92%, respectively. Also, the computation time in the MILP model is 112 s while that of MINLP is 1983 s. In comparison with the recent works [13], [17], and [19], the MINLP models are complicated and pose high computation time; on the other hand, achieving an optimum response cannot be guaranteed.

Therefore, based on the fast computation time of the MILP model (in comparison to MINLP model and the negligible deviation value), it can be concluded that the presented MILP model is practical one. For more clarification and investigation of efficiency, the MINLP and new MILP models are tested on two cases using different solvers: 1) solving the MINLP problem using BARON and COUENNE solvers, and 2) solving the MILP problem using CPLEX solver. As listed in Table I, the MILP model can solve the problem in all the cases in a low computation time but the MINLP solvers for IPDH cannot solve the problem in stage 2. As a result, the MINLP model cannot solve the mentioned problem for large-scale and integrated systems with high complexity. The observations show that the linear modeling is necessary for complex and large-scale problems to achieve an optimal solution with fast computation time.

Performance of decomposition algorithm: As mentioned, BD algorithm has a significant effect on the time of problem solving. The results are compared for three study cases with and without using the proposed method. As listed in Table II, the problem

$$\max_{\substack{P_{G_{i,t,h}};P_{DG_{i,t,h}};\\ P_{n,t,h};V_{i,t,h};G_{P_{nm,t,h}};}} E_{SP1}=\sum\left(\begin{array}{l} P_{D_{i,t,h}}\eta^{pd}_{i,t,h}+Q_{D_{i,t,h}}\eta^{qd}_{i,t,h}+M\left(1-\sum\limits_{f\in\Omega_{T_F}}(x_{JF_{ij,f,t}})\right)\\ \left(\overline{\gamma}^{pl}_{ij,t,h}-\underline{\gamma}^{pl}_{ij,t,h}+\overline{\gamma}^{ql}_{ij,t,h}-\underline{\gamma}^{ql}_{ij,t,h}\right)+\overline{\Delta V}_i\overline{\gamma}^{v}_{i,t,h,y}\\ +\sum\limits_{f\in\Omega_{T_F}}(\overline{S}_{L_{ij}}(x_{JF_{ij,f,t}}))\overline{\gamma}^{sl}_{ij,t,y}+\sum\limits_{m\in\Omega_{T_{DG}}}(\overline{S}_{DG_i}(x_{JDG_{i,m,t}}))\overline{\gamma}^{sd}_{i,t,y}\\ +\sum\limits_{s\in\Omega_{T_S}}(\overline{S}_{G_i}(x_{JG_{i,s,t}}))\overline{\gamma}^{sg}_{i,t,y}+\sum\limits_{m\in\Omega_{T_{DG}}}\left(\frac{\overline{P}_{DG_{i,t,h}}}{Y}\right)\overline{\gamma}^{pd}_{i,t,h,y}\\ +G_{D_{i,t,h}}\eta^{gd}_{i,t,h}+\sum\limits_{p\in\Omega_{T_P}}(\overline{G}_{P_{nm}}(x_{JP_{nm,p,t}}))\overline{\gamma}^{g_p}_{nm,t,h}\\ +\sum\limits_{m\in\Omega_{T_{DG}}}\overline{G}_{DG}(x_{JDG_{i,m,t}})\overline{\gamma}^{gd}_{n,t,h}+\sum\limits_{p\in\Omega_{T_P}}\left(\frac{\overline{P}_n}{Y}(x_{JP_{nm,p,t}})\right)\overline{\gamma}^{p}_{n,t,h,y}\\ +\sum\limits_{g\in\Omega_{T_{GS}}}(\overline{G}_{GS_g}(x_{JGS_{n,g,t}}))\overline{\gamma}^{gs}_{n,t,h} \end{array}\right) \quad (49)$$

TABLE I
COMPARISON OF VARIOUS MODELS AND METHODS

Cases	Models	Methods	Total Cost ($)	Time (sec) stage 1	Time (sec) stage 2
DP	MINLP	BARON	13,619,867	861	1983
	MINLP	COUENNE	13,557,159	1048	2449
	MILP	CPLEX	13,379,204	47	112
IPDH	MINLP	BARON	Infeasible	1681	Infeasible
	MINLP	COUENNE	Infeasible	2078	Infeasible
	MILP	CPLEX	10,278,617	96.2	217.3

TABLE II
RESULTS OF IMPLEMENTING THE BD ALGORITHM

	Method	DP	CPD	IPDH
Time (sec)	Without BD	112	198.6	217.3
	With BD	22.5	30.4	48.8

decomposition has increased the speed of the problem solving which is considerable in comparison to the problem solving without decomposition, in particular for integrated energy flow and large-scale problems.

The effectiveness of the integrated planning: Figs. 7 and 8 depict the network topology for decoupled and integrated planning. As shown in the topology, the expansion of the network is increased in stage 1 considering the load growth and new demand nodes. In case 1, the expansion of electricity substations, gas pipelines, and network feeders are needed. Also, the substations S1 and S2 have been changed from type (A) to type (B). In case 2, in comparison with case 1, due to the installation of new DG units in the network and the simultaneous power flow of electricity and gas, the network expansion is different. Noted that the differences in electricity network are due to the utilization of some feeders with low capacity (e.g., L3 and L29) and the reduction of installing new feeders (L19 and L20). In this case, based on the installation of DG resources, a part of power is provided by them leading to the reduction of electricity network expansion. Thus, in this case, the existing substations with DG units can supply the network demand and there is no need to expand them.

Also, using DG units leads to an increase in the capacity of some pipelines. Fig. 8 depicts the topologies of the network expansion in stage 2. In this stage, the electricity and gas networks have high complexity due to the increased demand and new load nodes. In this stage, the expansion of gas and electricity grids is similar to stage 1.

The costs of the network expansion and operation are listed in Tables III and IV. As given, in case 2, the network expansion is realized by a delay, thus, it has lower investment and operation cost compared to case 1.

The effectiveness of energy hubs: The topology of electricity and gas networks and expansion costs in case 3 are shown in Figs. 7 and 8 and Tables III and IV, respectively. Due to the

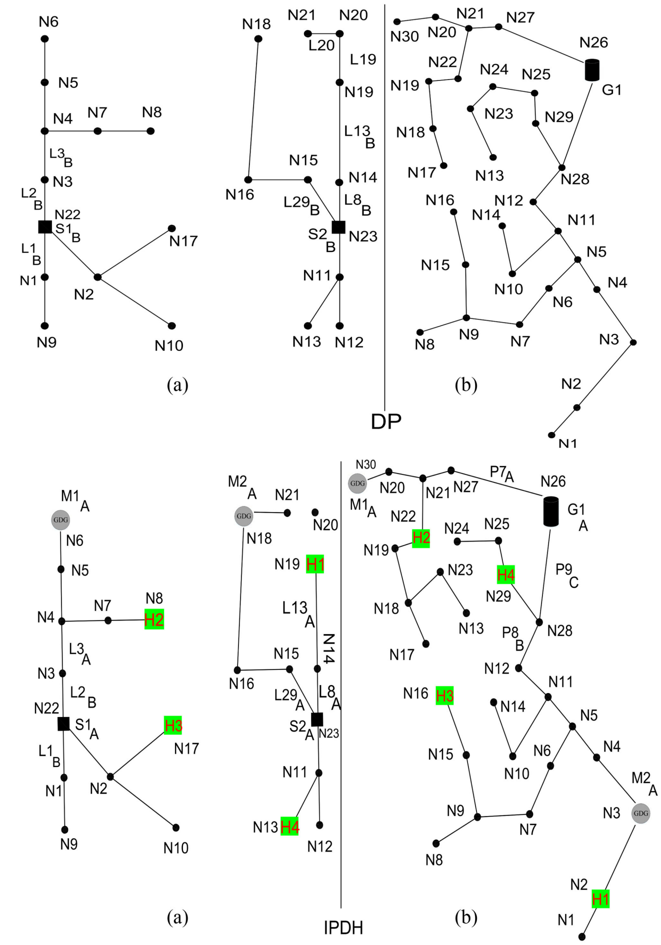

Fig. 7. Electricity and gas networks (stage 1).

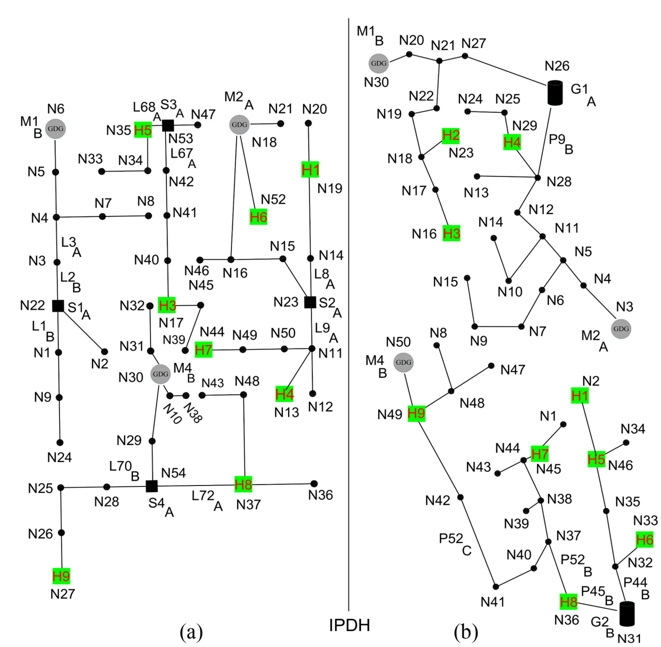

Fig. 8. Topologies of electricity and gas networks (stage 2).

TABLE III
PRESENT VALUE OF COSTS IN STAGE 1 ($)

Case	Investment Elc	Operation	Investment Gas	Total
DP	2,388,933	1,802,006	458,746	4,649,685
CPD	2,115,756	851,594	526,476	3,493,826
IPDH	1,670,856	714,830	586,330	2,972,016

TABLE IV
PRESENT VALUE OF COSTS IN STAGE 2 ($)

Case	Investment Elc	Operation	Investment Gas	Total
DP	7,326,288	4,597,837	1,455,079	13,379,204
CPD	6,775,607	3,011,057	1,700,937	11,487,601
IPDH	5,598,968	2,387,493	2,292,156	10,278,617

presence of energy hubs, the expansion of the electricity and gas networks is changed.

Indeed, at the nodes with energy hubs, a part of demand of different loads is provided via energy hub elements and the network expansion is performed with a delay. Also, in this case, a few DG units are required to be installed. The reduction of the electricity network expansion is due to energy hubs with CHP units and batteries.

The batteries generate electricity and CHPs generate heat to provide a part of cooling loads via absorption chillers. On the other hand, due to the reduction of the electricity network expansion and also providing a part of power via energy hub components in a decentralized manner, the operation cost is reduced.

Although the installation of CHP units needs the gas network expansion, due to the fact that a part of heat demand is also provided via CHPs, the gas network does not require too much expansion. The comparison of the expansion costs of the gas and electricity grids for three cases is listed in Table IV.

The case 3 has lower expansion cost of electricity network in comparison to cases 1 and 2. Thus, the reduction of the expansion and operation cost of electricity grid and installation of a few DG resources in case 3 can compensate the increase in expansion cost of gas network and totally this leads to lower expansion planning cost. Therefore, case 3 is the best choice for expansion planning of the electricity and gas networks due to the network integration and coplanning in the present article.

To evaluate the effectiveness of energy hubs optimization in the demand side, a comparison in terms of efficiency and EC for both cases (with and without using energy hubs) is depicted in Fig. 9.

As shown, based on the definition of the energy hubs as an interface in energy networks, the reduction of ECs in the electricity grid and increment in the natural gas grid are simultaneously observed due to application of CHP units at various nodes to provide a part of electrical demand because the cost of the purchased electrical energy from the grid is higher than the CHPs' one.

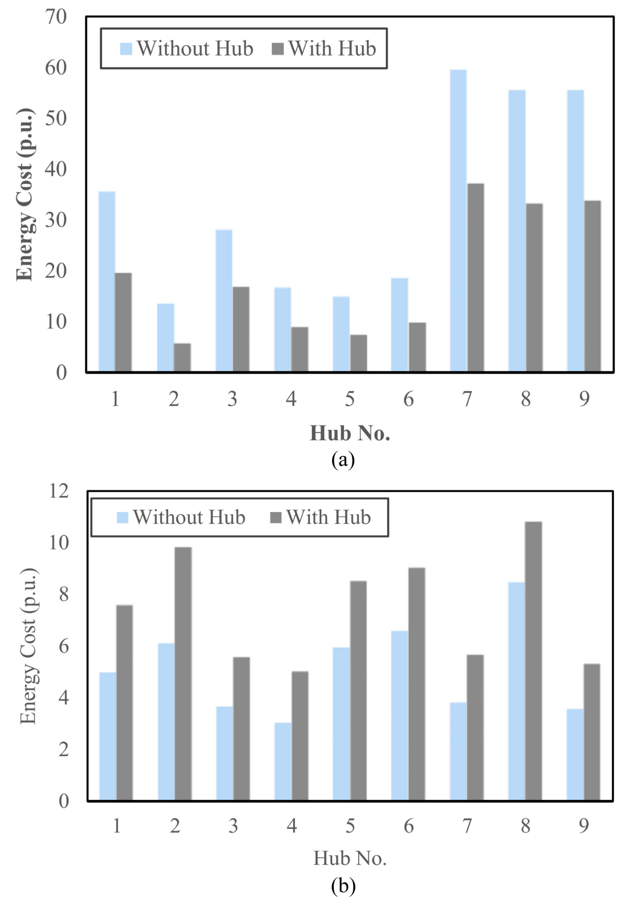

Fig. 9. Energy cost of nodes for (a) electricity (b) gas.

TABLE V
ENERGY COSTS FOR DECOUPLED AND INTEGRATED SYSTEMS

Cases	Without Energy Hub		With Energy Hub	
	Electricity	Gas	Electricity	Gas
Energy Cost	29,751.34	4617.31	16,950.16	6733.49
Total Cost	34,368.65		23,683.66	

On the other hand, its produced heat is used to provide cooling loads via absorption chillers and consequently, the electricity network demand is reduced and the total ECs are reduced about 31% (see Table V).

Compared to other researches described in the introduction, these results verify that the integrated planning and using energy hubs can have a significant effect on reduction of investment and operation costs of energy networks, reduction of ECs at the demand side and national resources conservation.

VI. CONCLUSION

The coplanning of the demand and supply sides and replacing various energy carriers reduces the investment and operation costs and increases the flexibility in energy supply. In this article, the modeling and integrated expansion planning of electricity and gas networks have been proposed using the energy hub concept. The implementation was via a new BLDA. The proposed model can represent the mutual physical and economic interactions of electrical and gas networks and is useful for the system planners and operators in demand and supply sides. One of the challenges for MCSs in comparison with single energy carrier systems is their problem complexity due to the nonlinear and nonconvex nature of the model. Thus, an MILP model has been proposed in this article. The MILP model guarantees achieving an optimal solution with acceptable accuracy in comparison to an MINLP model, especially in large-scale systems, and also the problem solution time has been significantly reduced. The simulation results have indicated an adequate efficiency of the proposed approach in MESs. The high coordination between operation and expansion planning of renewable-based energy hubs and distribution networks plays an important role in creating an optimal system. This issue is going to be considered in our future works based on an economic sensitivity analysis by taking into account the reliability and uncertainty criteria in different seasons.

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